

UNITED STATES OF AMERICA  
FEDERAL ENERGY REGULATORY COMMISSION

Joint Boards on Security  
Constrained Economic Dispatch

Docket No. AD05-13-000

SUPPLEMENTAL NOTICE OF SECOND NORTHEAST JOINT BOARD MEETING

(February 10, 2006)

On January 6, 2006, the Commission announced that it planned to hold further joint board meetings and that these meetings would take place at the Hyatt Regency on Capitol Hill, 400 New Jersey Avenue, N.W., in Washington D.C. Take notice that the joint board meeting for the Northeast region is scheduled to take place on Monday, February 13, 2006, from 9:45 a.m. to 12:15 p.m. (EST) in the Lexington/Bunker Hill Room.

These meetings are held pursuant to section 1298 of the Energy Policy Act of 2005, Pub. L. No. 109-58, § 1298, 119 Stat. 594, 986 (2005). Section 1298 adds section 223 to the Federal Power Act, 16 U.S.C. §§ 824 *et seq.* (2000), requiring the Commission to convene joint boards on a regional basis pursuant to FPA section 209 “to study the issue of security constrained economic dispatch for the various market regions,” “to consider issues relevant to what constitutes ‘security constrained economic dispatch’ and how such a mode of operating . . . affects or enhances the reliability and affordability of service,” and “to make recommendations to the Commission.”

Take further notice that attached are: (1) an agenda for the meeting, (2) a draft study previously circulated to the board members, and (3) recommendations to be considered by the board.

A complete and updated list of board members is available at [www.ferc.gov](http://www.ferc.gov).

For more information about the meeting, please contact Sarah McKinley at 202-502-8004 or [sarah.mckinley@ferc.gov](mailto:sarah.mckinley@ferc.gov).

Magalie R. Salas  
Secretary

Attachment A

**AGENDA FOR THE NORTHEAST JOINT BOARD MEETING  
February 13, 2006**

- Opening remarks
- General comments on draft study previously circulated
- Recommendations proposed during the course of the Joint Board's activities
  - Recommendations for the Board's consideration are attached to this agenda
- Process for subsequent drafts
- Next steps and closing remarks

Attachment B: Draft Study

**DRAFT**

**Study of Security Constrained Economic Dispatch (SCED) in the Northeast**

**by**

**The Joint Board on Economic Dispatch for the Northeast Region**

**Date, 2006**

## Overview

The Northeast Joint Board is one of four joint boards designated by the Commission under EAct2005, Section 1298 Economic Dispatch.

As the Commission noted in the initial order convening the joint boards:

Each joint board is authorized: (1)“to consider issues relevant to what constitutes ‘*security constrained economic dispatch*’”; (2) to consider “how such a mode of operating an electric energy system affects or enhances the reliability and affordability of service to customers in the region concerned”; and (3) “to make recommendations to the Commission regarding such issues.”

In the following sections, this report provides a description of the basic concept of Security Constrained Economic Dispatch; describes background on the variations in dispatch procedures in the Northeast, and gives a summary of the issues raised and considered by the board, together with any recommendations made to address these issues. The principal sources for these sections are presentations to the board and written comments submitted, discussions among the Joint Board members, the DOE report under EAct 2005, Section 1234 and the responses to the DOE survey of economic dispatch under Section 1234.

## Security Constrained Economic Dispatch: The Basics

For purposes of the joint boards’ studies, the FERC adopted the following definition of security constrained economic dispatch: “the operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operational limits of generation and transmission facilities.”<sup>1</sup> This definition describes the basic way all utilities or ISOs/RTOs dispatch resources to meet electricity load. The basics of security constrained economic dispatch are described in this section to establish a common understanding of the process before addressing issues and recommendations.

There are a number of unique challenges to supplying electricity: production must occur simultaneously with demand, demand varies greatly over the course of a day, week, and seasons, the costs of generation from different types of units vary greatly, and expected and unexpected conditions on the transmission network affect which generation units can be used to serve load reliably. Security constrained economic dispatch is an optimization process that takes account of these factors in selecting the generating units to dispatch to deliver a reliable supply of electricity at the lowest cost possible under given conditions.

---

<sup>1</sup> September 30, 2005 order at P14.

The economic dispatch process occurs in two stages, or time periods: day-ahead unit commitment (planning for tomorrow's dispatch) and unit dispatch (dispatching the system in real time).

In the *unit commitment* stage, operators must decide which generating units should be committed to be on-line for each hour, typically for the next 24-hour period (hence the term "day ahead"), based on the load forecast. In selecting the most economic generators to commit, operators must take into account each unit's physical operating characteristics, such as how quickly output can be changed, maximum and minimum output levels, and minimum time a generator must run once it is started. Operators must also take into account generating unit cost factors, such as fuel and non-fuel operating costs and costs of environmental compliance.

In addition, forecasted conditions that can affect the transmission grid must also be taken into account to ensure that the optimal dispatch can meet load reliably. This is the "security" aspect of the commitment analysis. Factors that can affect grid capabilities include generation and transmission facility outages, line capacities as affected by loading levels and flow direction, and the weather. If the security analysis indicates that the optimal economic dispatch cannot be carried out reliably, relatively expensive generators may have to replace cheaper units.<sup>2</sup> Operators might perform the unit commitment analysis a few times during the day before actually committing generators for the next day dispatch.

In the *unit dispatch* stage, operators must decide in real time the level at which each available resource (from the unit commitment stage) should be operated, given the actual load and grid conditions, such that overall production costs are minimized. Actual conditions will vary from those forecasted in the day-ahead commitment and operators must adjust the dispatch accordingly. As part of real time operations, demand, generation, and interchange (imports and exports) must be kept in balance to maintain a system frequency of 60 Hz (per NERC standards). This is usually done by using Automatic Generation Control (AGC) to change the generation dispatch as needed. In addition, transmission flows must be monitored to ensure flows stay within reliability limits and voltage within reliability ranges. If transmission flows exceed accepted ranges, the operator must take corrective action, which could involve curtailing schedules, changing the dispatch, or shedding load. Operators may check conditions and issue adjusted unit dispatch instructions as often as every five minutes.

The manner in which transmission and operational limitations of generators have been represented in unit commitment and economic dispatch software has not been uniform

---

<sup>2</sup> This is known as "out of merit" dispatch.

across the industry. For example, some unit commitment software packages might represent the entire transmission network in detail while others might only represent selected transmission constraints to make the problem easier to solve. Similarly, the representation of unit operational constraints and in some cases even the network model might vary in economic dispatch software.

The economic dispatch problem is generally considered to be a mathematically simpler problem to solve although recent advances (e.g. the use of mixed-integer-programming (MIP) for unit commitment) have advanced the available technology to the point where many earlier limitations on problem size have been eliminated. Advances in hardware and software now make it technologically feasible to undertake security constrained economic dispatch over large regions.

In addition to differences in models used in economic dispatch software, a major factor that can impact the benefits of economic dispatch is whether or not all available resources are considered. In non-organized markets this may not always be possible due to various reasons including limitations in open access transmission tariffs based on Order 888.

### **Economic Dispatch in the Northeast**

Security Constrained Economic Dispatch (SCED) in the northeast is performed primarily by two entities – ISO New England (ISONE) and the New York ISO (NYISO). Both entities have been designated as Regional Transmission Organizations (RTOs) and operate day-ahead and real-time energy markets that constitute the commitment and dispatch components of SCED described in the last section. There is a long history of SCED in the Northeast under these entities and prior to this under the NY Power Pool and NEPOOL.

There is much in common between the two regions in how they perform SCED. Both NYISO and ISO-NE have consolidated control areas and perform the dispatch function centrally. SCED has been performed in both regions since the 1970s under the predecessor power pools and continues with enhancements under the markets that have been in operation since 1999. They both incorporate transmission constraints and unit operational constraints within the dispatch and commitment software. They both include all available resources without regard to ownership. Both regions have significant load pockets, e.g., New York City, Boston and SW Connecticut that require out-of-merit dispatch. Both regions have had limitations on reflecting the full spectrum of physical constraints in their software that has resulted in uplifts, i.e., costs that are not included in the market price and are administratively allocated to participants. Currently, this appears to be a bigger problem in New England.

## **NYISO and NYPP**

The NYPP was formed in response to the Northeastern blackout of 1965. By 1977 it had implemented a form of SCED that dispatched all of the utility-owned generation in New York State based not on market-driven bidding, but on regulated generator costs that were established through cost-of-service ratemaking. The NYPP SCED did not incorporate non-utility generation. Nevertheless, it produced substantial savings by dispatching generation on a least-cost basis and by taking advantage of supply and load diversity across the pool. The resulting savings were split among the NYPP's utility members and went to the ultimate benefit of ratepayers.

The NYPP SCED made it possible for energy transactions to be scheduled and priced more efficiently than was possible before 1977. Prior to the SCED, the NYPP could only facilitate bilateral transactions among its member utilities by acting as an intermediary. This was done through telephone calls and allowed transactions to be scheduled on, at best, an hourly basis. Under SCED, transaction scheduling and pricing was fully automated and took place every five minutes. In addition, the adoption of SCED allowed the NYPP to develop an "Interchange Evaluation" program, which evaluated energy transactions between neighboring control areas in the United States and Canada, including New England, the mid-Atlantic, Ontario and Quebec. This evaluation optimized inter-control area energy deliveries in the Northeast and made out-of-state economic resources more readily available to the NYCA.

The adoption of SCED also permitted a more efficient allocation of Operating Reserves among NYPP members to satisfy total pool requirements. The NYPP estimated that SCED, and the various external transaction scheduling improvements that it made possible, was responsible for \$281 million in savings in 1981, which would translate to approximately \$600 million in 2005 dollars.

In the 1990s, the NYPP's members formed the NYISO. From its inception in 1999, the NYISO used a bid-based SCED that was open to all electricity resources in the NYCA, and to out-of-state suppliers selling into New York, that chose to participate in it. The NYISO SCED is a key part of the NYISO's market that uses a locational-based marginal pricing system ("LBMP") very similar to the locational marginal pricing (LMP) regimes that have evolved in the ISO New England, PJM Interconnection, and Midwest Independent System Operator regions.

The NYISO implemented major enhancements to its real-time dispatch and market software on February 1, 2005. It now has fully co-optimized day-ahead and real-time markets for energy, three different reserves products, and regulation that produce the lowest possible total cost for these products consistent with reliability constraints. The NYISO's new software platform includes a real-time unit commitment ("RTC") function

that complements the NYISO's day-ahead security constrained unit commitment process using the superior information that becomes available closer to the actual real-time dispatch. RTC is capable of looking two and a half hours ahead and can commit "quick start" resources such as hydro units and certain gas turbines in fifteen minute increments in order to facilitate a more efficient co-optimized, least-cost SCED for energy ancillary services. The RTC is integrated with and uses the same software as the NYISO's real-time dispatching system, which helps them to work together to produce the best possible dispatch and price signals. There are nearly three hundred active market participants in the NYISO markets today. In 2004, the NYISO settled electricity transactions totaling approximately \$7.3 billion and has cleared over \$30 billion of wholesale transactions since its inception in 1999.

### **ISO-NE and NEPOOL**

The New England Power Pool (NEPOOL) was formed in 1971 by the region's private and municipal utilities to foster cooperation and coordination among utilities in the six-state region. During the next three decades, NEPOOL created a regional power grid that now includes more than 350 separate generating plants and more than 8,000 miles of transmission lines.

ISO New England was created in 1997 in a region where 88 percent of the region's generation is unregulated, the most in the nation. Working closely with the NEPOOL, now a group of generators, utilities, marketers, public power companies and end users, ISO New England implemented wholesale markets in 1999. Today, more than 260 Market Participants complete in excess of \$10 billion of wholesale electricity transactions annually, about a quarter of the power sold in the region (the remainder is sold through negotiated, long-term contracts).

ISO New England has enhanced these markets, notably in 2003, by adding features such as a Day-Ahead Market. In the five years following the opening of wholesale markets in 1999, New England's capacity has increased by 40 percent. Wholesale electricity prices in New England, adjusted for fuel costs, have declined by 5.7 percent since the first full year of market operations. Prices dropped by 11 percent during the four-year period from 2001-2004.

Security Constrained Economic Dispatch (SCED) is an essential component of the ISO-NE markets. It figures in the day-ahead unit commitment performed under the day-ahead market and in the real-time balancing market.

New England's Economic Dispatch is coordinated with the Economic Dispatch of neighboring control areas through hourly exports and imports of power. These exports and imports are generally scheduled by market participants responding to electricity

prices in each control area, with participants seeking to buy power in the lower priced control area and sell in the higher priced control area. If the volume of transactions increases until either the prices at the source and delivery points are equal, or until the transfer limits are reached, then the dispatch is efficiently coordinated between the control areas. Because this efficient coordination does not regularly occur between New York and New England, the two control areas are investigating ways to improve the coordination. Possible solutions include the two ISO's explicitly coordinating interface flows and reducing the lead time required for participants to schedule flows across the interface between the regions.

## Observations and Issues

This section describes the issues considered by the Joint Board and identifies any recommendations in the record. Based on the discussion at the initial meeting, there appeared to be an overall consensus that economic dispatch and markets have created benefits for customers in the Northeast. There is a long history of economic dispatch in the region that was mentioned by many participants along with an emphasis on least cost security constrained dispatch without regard to ownership<sup>3</sup>. There was some disagreement on the precise measure of these benefits.

## Observations

- *Benefits from economic dispatch*

The NYISO estimated the benefits of SCED at roughly 100 million dollars per year from 1977 to 1999 yielding a cumulative benefit of 2 billion dollars<sup>4</sup>. A savings of 281 million dollars or roughly 24 percent of the total market transactions was cited in 1981. Precise estimates for the period since 1977 were not cited. However, the NYISO has made several enhancements to SCED since then and estimates that the benefits have likely increased even further. The NYISO cited estimated a five percent decline based on average monthly costs on a fuel adjusted basis from 2000 – 2004<sup>5</sup>.

ISO-NE cited an estimated total savings due to the regional economic dispatch from 1970 – 1977 at over \$1.4 billion in 2004 dollars<sup>6</sup>. The ISO-NE cited a 5.6 percent reduction in the average wholesale cost of electricity from 2000-2004

---

<sup>3</sup> Mr. Bolbrek at p 111 of transcript.

<sup>4</sup> Mark Lynch at p 49 of transcript.

<sup>5</sup> Mark Lynch at p 59 of transcript.

<sup>6</sup> Gordon van Welie at p 66 of transcript.

which translates to a 700 million dollars per year after netting out fuel costs<sup>7</sup>. The ISO-NE also noted a 5 - 6 percent improvement in generator availability and significant new investment as a result of the advent of markets.

Despite the extensive references to the benefits of economic dispatch and markets in general, there were also concerns raised on related market issues (e.g., the impact of high gas prices on uniform price markets) as well as a discussion of further improvements than can be made, e.g. improved inter-regional coordination, better modeling of constraints in software etc. In the remainder of this section, we summarize some of the major issues that were brought up.

- *Benefits of economic dispatch and benefits of markets*

There was considerable discussion at the meeting on the benefits that have been realized through markets. Some participants suggested that since economic dispatch is a required enabler of markets, it makes sense to look at the benefits created by the market as a whole when evaluating the benefits of economic dispatch<sup>8</sup>. Others disagreed observing that economic dispatch does not necessarily require markets<sup>9</sup>.

Some participants observed that improvements in generation availability may not be entirely attributable to the introduction of LMP based day-ahead markets but rather a result of how capacity credits are calculated<sup>10</sup>. Measuring the benefits of economic dispatch precisely can be complex<sup>11</sup>.

- *Concerns about efficient vs. economic dispatch*

Some participants raised questions about whether economic dispatch can ensure efficient dispatch<sup>12</sup>. The difference between economic and efficient dispatch has been discussed in the recent DOE report related to section 1234 of EPACT. The reasons the two can be different are two-fold (1) if the entire set of available resources is not considered as an input to the economic dispatch algorithm, the

---

<sup>7</sup> Gordon van Welie at p 68 of transcript.

<sup>8</sup> Gordon van Welie at p 67 of transcript.

<sup>9</sup> Mr. Rudebusch at p 162 of transcript.

<sup>10</sup> Mr. Bolbrock at p85 of transcript.

<sup>11</sup> Mr. Burke at p 99 of transcript.

<sup>12</sup> Keating, Meyer and Meroney at pp 26-30 of transcript.

result will not be efficient<sup>13</sup>, and (2) if offer prices do not reflect costs, the dispatch may not be efficient from a heat-rate perspective<sup>14</sup>.

### **Specific Market and Dispatch Issues**

- *Wider geographical scope of economic dispatch*

Some improvements such as the elimination of pancaking in rates have already been made<sup>15</sup>. Other improvements that are under way include better inter-regional transaction scheduling and pricing of external nodes<sup>16</sup>. Overall, there appears to be consensus that better coordination of dispatch across interfaces within the region (e.g. New York and New England) as well as interfaces with external areas (e.g., PJM and Canada) is desirable. However, some participants also raised caution on what might be a reasonable expectation of benefits.

There is disagreement on specific approaches to improve coordination of economic dispatch between New York and New England. Some participants favored improvements realized through improved transaction scheduling by market participants on a shorter time frame than is available currently, while others favored a stronger integration using a “Virtual Regional Dispatch” (VRD) model<sup>17</sup>. Both the New York ISO and ISO New England have looked at the VRD approach for some time with little actual progress on implementation. More recently, they have started looking at taking smaller steps by improving the granularity of scheduling across their boundaries under the Interregional Transaction Scheduling or ITS project. By allowing schedules to be submitted closer to real-time and more frequently, the expectation is that market participants would be able to capture at least some of the benefits that can come from a fully integrated economic dispatch. Some participants raised concerns about implementation complexity and costs<sup>18</sup>.

---

<sup>13</sup> Meroney at p 28 of transcript.

<sup>14</sup> Keating at p 30 of transcript.

<sup>15</sup> Mark Lynch at p. 60 of transcript.

<sup>16</sup> Gordon van Welie at p 78 of transcript.

<sup>17</sup> See comments submitted by National Grid, Dan Allegretti at p 106 and Michael Calviou at p 118 of transcript.

<sup>18</sup> Mr. Loughney at p 160 of transcript.

- *Concerns about uniform price markets*

In response to the recent high gas prices and their impact on electricity prices, there have been concerns expressed about uniform clearing price markets and whether there could be additional savings under other market models<sup>19</sup>. A report written during the California power crisis that explained the benefits of uniform price auctions and why it ultimately results in lower prices for customers was cited<sup>20</sup>. However, some participants expressed a desire to revisit the issue using actual bidding data and a more realistic assumption of generation mix<sup>21</sup>. Some participants noted that economic dispatch does not necessarily require a single clearing price methodology and took issue with prices set by gas fired plants being paid to coal and nuclear plant<sup>22</sup>. Other participants noted that the alternative design of pay-as-bid auctions could potentially result in lower overall prices but this would destroy incentives for cost reflective bids, which in turn would lead to inefficient dispatch and may not be worth the complexity<sup>23</sup>.

- *Improvements in modeling of unit operational constraints and transmission constraints in economic dispatch*

Some participants raised concerns about dispatch actions taken outside the security constrained economic dispatch software<sup>24</sup>. Such actions are necessary when either the operational constraints of generators or transmission constraints cannot be fully represented within the software. Generating sources dispatched in this manner do not affect the calculation of market prices and are paid separately via an uplift payment. If uplifts are improperly allocated to market participants they can have additional adverse affects on markets. One example cited at the conference was the impact of uplifts allocations in New England and their impact on virtual trading. The allocation has recently been modified to address the problem<sup>25</sup>. One participant noted that the biggest issue is the challenge in reflecting all security constraints in security constrained unit commitment and security constrained economic dispatch<sup>26</sup>.

---

<sup>19</sup> Commissioner Brownell at p 97 of transcript.

<sup>20</sup> Gordon van Wylie at p 97 and p 182 of transcript. The report "Pricing of the California Electricity Market - Should California Switch from Uniform Pricing to Pay-As-Bid Pricing" is available as a part of the record.

<sup>21</sup> Bob Loughney at p 158 of transcript.

<sup>22</sup> Mr. Rudebusch at p 162 of transcript.

<sup>23</sup> Harry Singh at p 187 and Don Sipe at p 198 of transcript.

<sup>24</sup> Pete Fuller at p. 43, Dan Allegretti at p 105 and Steve Corneli at p 139 of transcript.

<sup>25</sup> Steve Corneli at p 140 of transcript.

<sup>26</sup> Steve Corneli at p 138 of transcript.

There have been recent improvements to dispatch models used in the Northeast. For example, NYISO introduced in February 2005, enhancements to its real time dispatch software that allows co-optimization of energy and reserves in addition to a shortened evaluation period for real-time unit commitment<sup>27</sup>.

Uplifts can often result from limitations of software in modeling physical constraints, e.g. combined cycle plants in unit commitment in the Boston area. The economic impact of such uplifts can in some instances be greater than efficiency gains on seams issues. The ISO-New England has therefore made addressing this issue a high priority<sup>28</sup>.

Other improvements such as the use of Mixed Integer Programming (MIP) software for better combined cycle generator modeling are being considered but are in the research and development phase<sup>29</sup>.

- *Incorporation of demand response into economic dispatch*

There are opportunities for better integration of demand response in economic dispatch that can further improve infrastructure utilization<sup>30</sup>. This is an area where state regulators and the RTOs can work together. Participants noted that while organized markets have generally similar demand response programs, there are also differences. For example, ISO New England considers demand response to be a critical resource that can be drawn upon in the absence of quick start peaking resources and has made efforts to incorporate demand response into its commitment and dispatch software<sup>31</sup>.

- *Further Improvements in market transparency*

Many participants noted the significance of transparent price signals in making markets work better and encouraging investment. Some participants expressed a desire to allow releasing market bid data sooner than the six-month lag with which is released currently<sup>32</sup>. They cited other markets such as the UK and Australia where this is done on a daily basis and argued that US markets have now matured

---

<sup>27</sup> Mark Lynch at pp 59-60 of transcript.

<sup>28</sup> Gordon van Welie at p 78 of transcript.

<sup>29</sup> Gordon van Welie at p74 of transcript.

<sup>30</sup> Gordon van Welie at p 72 and p 83 of transcript and Burke at p 93 of transcript.

<sup>31</sup> Gordon van Welie at p 90 of transcript.

<sup>32</sup> Michael Calviou at p 122 and Doug Horan at p 148 of transcript.

enough to allow this data to be released sooner. The ISO-NE responded saying they would be open to such a suggestion and the right venue to discuss it would be the stakeholder committee process<sup>33</sup>.

- *Better utilization of the interconnections with External Areas*

Additional benefits of economic dispatch may be possible by looking at external interfaces with regions outside New York and New England. A specific example was the 2000 MW limit on the Phase 2 HVDC U.S. Interconnector between New England and Quebec that is currently being used at 1200 MW due to constraints further down the system in New York and PJM<sup>34</sup>. A decrease in flows from Quebec to New York may be able to yield as much as three times higher flows into New England. Thus, further benefits for the region may be possible by improved coordination between New York, New England and Quebec.

- *Capacity markets and new investments* – One participant noted that existing markets have not performed well in promoting new investment through price signals. Instead, new investment is largely driven by contracts arranged via RFPs. A missing element of markets in the region relates to the refinement of existing mechanisms for capacity markets<sup>35</sup>.

## **Recommendations from the DOE Report to Congress**

The DOE Report to Congress, *The Value of Economic Dispatch*, contains three recommendations that are relevant to the security constrained economic dispatch issues that the Joint Board has been considering. These three recommendations are described below.

- FERC-State Joint Boards should consider conducting in-depth reviews of selected dispatch entities, including some IOUs, to determine how they conduct ED.<sup>36</sup> These reviews could document the rationale for all deviations from pure least cost, merit-order dispatch, in terms of procurement, unit commitment and real-time dispatch. The reviews should distinguish entity-specific and regional business

---

<sup>33</sup> Gordon van Welie at p 129 of transcript.

<sup>34</sup> See Michael Calviou at p 120 of transcript.

<sup>35</sup> Steve Corneli at p 142 of transcript.

<sup>36</sup> *The Value of Economic Dispatch, A Report to Congress Pursuant to Section 1234 of the Energy Policy Act of 2005*, United States Department of Energy, November 7, 2005, page 52.

practices should from regulatory, environmental and reliability-driven constraints. These reviews could assist FERC and the states in rethinking existing rules or crafting new rules and procedures to allow NUGs and other resources to compete effectively and serve load.

- FERC and DOE should explore EPSA and EEI proposals for more standard contract terms and encourage stakeholders to undertake these efforts.<sup>37</sup> Specifically, the EEI proposed that NUGs should commit to provide energy at specified price for specified time to meet unit commitment schedule and there should be contractual performance standards with penalties for failure to deliver. EPSA proposed developing technical protocols for placing and accepting supply offers, operational requirements, non-performance penalties, and standard contract forms for routine transactions.
- Current economic dispatch technology tools deserve scrutiny.<sup>38</sup> These tools include software and data used to implement economic dispatch, as well as the underlying algorithms and assumptions.

## **Board Recommendations**

*To be discussed at the next meeting and completed by board members.*

---

<sup>37</sup> Ibid, p 51.

<sup>38</sup> Ibid, p 53.

## Attachment C

### RECOMMENDATIONS FOR CONSIDERATION BY THE NORTHEAST JOINT BOARD

#### Recommendations Found in the Record of the Northeast Board

- *Further Improvements in Market Transparency* – A proposal was made to allow market bid data to be released with a less than six-month lag. It was supported by at least one other party. The ISO NE stated that it was open to suggestions on making market bid data available with a shorter lag time and that this should be pursued through the appropriate committee process.
- *Wider geographical scope of economic dispatch* - Some participants recommended further improvements in regional economic dispatch through improvements in transaction scheduling across regional interfaces by market participants on a shorter time frame than is available currently, while others favored a stronger integration using a “Virtual Regional Dispatch” (VRD) model.
- *Improvements in modeling of unit operational constraints and transmission constraints in economic dispatch* – Several participants noted the need to better reflect security constraints in the security constrained economic dispatch.
- *Incorporation of demand response into economic dispatch* – Some participants called for better integration of demand response into economic dispatch and for state regulators and RTOs to work together on this.
- *Better utilization of the interconnections with External Areas*- Some participants called for better coordination between neighboring areas to improve the utilization of interfaces with Quebec.
- *Refining capacity markets* – Some participants called for refinements to capacity markets in order to promote new investment.
- *Re-examining uniform price auctions* – Some participants called for re-examining the use of uniform price auctions that allow gas fired generators to set the price for coal and nuclear plant.
- *Review dispatch practices* - Review selected dispatch entities, including some investor-owned utilities, to determine how they conduct economic dispatch. These

reviews could document the rationale for all deviations from pure least cost, merit-order dispatch, and distinguish entity-specific and regional business practices from regulatory, environmental and reliability-driven constraints. (DOE Report at 52)

- *Standardize contract terms* - Recommend that FERC and DOE explore Electric Power Supply Association (EPSA) and Edison Electric Institute (EEI) proposals for more standard contract terms and encourage stakeholders to undertake these efforts. (DOE Report at 51)
- *Review dispatch tools* - Review current economic dispatch technology tools. These tools include software and data used to implement economic dispatch, as well as the underlying algorithms and assumptions. (DOE Report at 53)